

EXPERIMENTAL INVESTIGATION ON THE EFFECT OF LOW  
SALINE WATER (LSW) DURING FAWAG-CO<sub>2</sub> ON LIGHT OIL

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## CERTIFICATION OF APPROVAL

### **Experimental Investigation on the Effect of Low Saline Water (LSW) During FAWAG-CO<sub>2</sub> on Light Oil**

by

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September 2013

## CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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## **ABSTRACT**

Water flooding for a long time has been regarded as a secondary oil recovery method which can considerably increase oil production. However, even in this case, a significant amount of oil is still trapped in the reservoir. So far, to recover the remaining oil, various methods as tertiary recovery processes have been proposed. In the water flooding, it is usually pointed out that injection of low saline water change wetting properties of the reservoir during a water flood in a favorable way to improve oil recovery due to salinity. In the tertiary recovery, several EOR methods such as continuous Gas Injection, Water Alternating Gas flooding (WAG), Simultaneous Water Alternating Gas flooding (SWAG), and Foam Assisted Water Alternating Gas (FAWAG) process have been studied. Among these methods due to high mobility control in the gas flow, FAWAG process has been found to be more feasible.

Hence, in this work based on the acceptable performance of the foregoing methods, FAWAG process is improved with low saline water. For this purpose, the oil recovery factor is compared between the application of formation water (high salinity brine) and low salinity brine during FAWAG-CO<sub>2</sub>. Type of surfactants to be used already finalized, only salinity of the brine is changing. However, several chemical screening tests will be conducted. Coreflooding will be done to determine the effect of low saline water during FAWAG on oil recovery.

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## ABBREVIATION AND NOMENCLATURES

A	Area
CEC	Cation Exchange Capacity
cp	Centipoise
cc	Cubic centimetre
CO <sub>2</sub>	Carbon Dioxide
EOR	Enhanced Oil Recovery
$\phi$	Porosity
°C	Degree Celcius
°F	Degree Fahrenheit
FAWAG	Foam-Assisted Water Alternated Gas
FW	Formation Water
ft	Feet
g/L	Gram per liter
iWAG	Immiscible WAG
k	Permeability
Kair	Air Permeability
Kif	Klinkenberg Permeability
LSW	Low Saline Water
mD	Permeability in miliDarcies
ml	milliliter
MMP	Minimum Miscibility Pressure
NaCl	Sodium Chloride
OOIP	Original Oil In Place
Pc	Capillary Pressure
psi	Pound per square inch
psig	pounds per square inch gauge
PV	Pore Volume
SDS	Sodium Dodecyl Sulphate
SLS	Sodium Lauryl Sulphate
Soi	Intial Oil Saturation
SS	Steady State
Sw	Brine Saturation/ Water Saturation
Swc	Connate Water Saturation
USS	Unsteady State
wt. %	weight percentage



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# **CHAPTER 1: INTRODUCTION**

## **1.1 Project Background**

Traditionally, oil recovery operations have been subdivided into three stages: primary, secondary and tertiary. These stages described the production from a reservoir in a chronological sense. Primary recovery result from the use of natural energy presents in a reservoir as the main source of energy for the displacement of oil to the production. Secondary recovery results from the augmentation of natural energy through injection of water or gas to displace oil towards producing wells.

Waterflooding is proved the most popular and successful method in primary-oil recovery mechanisms especially in water-wet reservoir. This recovery method had been used on numerous fields and responsible for the recovery of 20 to 30 percent of the original oil in place. However, after secondary recovery process, still significant amount of oil is trapped in the reservoir.

In order to recover the residual oil, tertiary recovery process is utilized. This process is known as enhanced oil recovery (EOR). This process includes the injection of gases, liquid chemicals and thermal energy. Among these, gas-injection-based EOR is a more popular method to recover this enormous resource base effectively. However, gas-injection posed certain problems. Despite their high microscopic displacement efficiencies, Injected gases characteristics of very low density and viscosity caused it to have very high and unfavorable mobility ratios which can cause severe fingering and gas-oil gravity segregation with large unswept reservoir volume. Volumetric sweep efficiency of these EOR process will be low.

In order to overcome this major shortcoming and improve sweep efficiency, water alternated gas (WAG) process had been widely practiced. This process is not only control the mobility of gas, gas consumption is also been reduced. However, the presence of increased mobile water saturation will cause water shielding in which water

films prevent oil and gas coming into direct contact and for miscible gas injection it delays the onset of miscibility resulted in poor recovery of the WAG process.

Another alternative technique of improving sweep efficiency during gas injection is the uses of foam. This technique is known as foam-assisted WAG (FAWAG). It has the ability to reduce the produced gas-oil ratio and maximizing production rate in the producing well. Moreover, foam is used with WAG technique to solve the problems faced by the well such as overriding caused by thief zone or gravity override. Furthermore, in heterogeneous formations, foam generation will occur in the high permeability zones first which divert the fluid flow towards low permeability zones.

To further improve the sweep efficiency, role of water salinity had been widely focused through many researches. It is well known that low salinity flood has many advantages such as high EOR potential, environmentally friendly, and combination with other possible recovery methods. As for this research project, low saline water is applied to improved FAWAG process. The methodological plan in this study is to do an experimental investigation on the effect of salinity. For this purpose, the effects of low salinity and effective range of salinity on FAWAG process will be investigated.

## **1.2 Problem Statement**

### **1.2.1 Problem Identification**

Foam has been applied in four different pilots on the Norway Snorre field. The pilots covered gas shut off in production wells, and mobility control with foam-assisted WAG injection (FAWAG) for diversion of injected gas. A lot of studies on the FAWAG pilots have been done by simulation of FAWAG and consideration of foam and foam behavior, but there is no laboratory and detailed study which relate the effects of water salinity on foam and residual oil saturation during FAWAG process. It is widely recognized that the reservoir wettability affects the relative distribution of fluids within a porous medium, which in turn strongly affects the displacement behavior, relative

permeability characteristics and consequently the production of hydrocarbons from petroleum reservoirs.

To the best of our knowledge, no efforts have been made to critically address the recovery of residual oil by combination of low saline water and FAWAG process in the literature. It has been found that, there is a pressing need for studying the combined effect of low saline water on FAWAG process. Thus, this will be the basis of the research.

### **1.2.2 Significance of the project**

This research able to address the relationship between the parameters that are responsible for wettability alteration which in turn will affect the success or failure of the proposed hybrid FAWAG process with low saline water injection. A thorough investigation will be done to assess all the factors that will be contributing to increased oil recovery.

### **1.3 Relevancy of the Project**

In this research, conventional FAWAG-CO<sub>2</sub> process will be improved with the introduction of low saline water. In previous research, low saline water has the ability to alter the wettability into more water-wet which is more favorable for oil recovery. However, This research will compare the performance of using FW or LSW in FAWAG process.

. Foam is used to control gas mobility and gas overriding. Therefore, improved sweep efficiency. This research will compare the performance of using FW or LSW in FAWAG process.

## **1.4 Project Objectives**

The main objective of this research is to investigate the effect of low saline water injection combined with FAWAG-CO<sub>2</sub> process on oil recovery. This experimental study has the following sub-objectives:

1. To investigate the effect of LSW on foam-formation integrity
2. To investigate the effectiveness of hybrid application of FAWAG-CO<sub>2</sub> and LSW injection on oil recovery compared to the conventional FAWAG-CO<sub>2</sub> application

## **CHAPTER 2: LITERATURE REVIEW**

### **2.1 Enhanced Oil Recovery (EOR)**

For the fact that recovering oil from mature fields is becoming more and more vital as finding new oil is not easy, there is a growing need to increase the output and ultimate recovery by EOR methods. This has been assumed of a great significance as far as mature oil fields are concerned.

EOR is a term applied to methods used for recovering oil from a petroleum reservoir beyond that recoverable by primary and secondary methods. Thus, EOR is often synonymous with tertiary recovery. Various methods of EOR are essentially designed to recover residual oil left by both primary and secondary recovery methods.

### **2.2 Waterflooding**

After natural drive mechanisms are no longer able to recovery oil economically, secondary recovery is employed. The most common method of secondary recovery is perhaps waterflooding. Water is injected for pressure maintenance and displaced oil microscopically. However, waterflood oil microscopic displacement is very poor especially in oil-wet reservoir.

There is several factor affects the displacement efficiency of waterflooding:

1. Mobility Ratio: displacement efficiency can be increased by reducing the mobility ratio which can be done by increasing the viscosity of water. High mobility ratio will cause water fingering and early water breakthrough which is faster in high permeability reservoir.
2. Lithology and rock properties: water injected might cause clay swelling and deflocculating which will clog the pores and damage the formation permeability. Water injection rate also had to be monitored to make sure that it does not exceed the formation fracture pressure. Waterflood also recover more oil in water-wet system as it can enter smaller pores due to capillary pressure.
3. Trapped Gas Saturation, Sgt: if the reservoir pressure is carefully maintained, optimum Sgt can exist within the oil bank. Higher Sgt can reduce the residual oil saturation. (Willhite, 1986). This is due to gas is more non-wetting to the reservoir rock than oil. As water displaced the oil, amount of residual oil left in the larger pore spaces would be reduced because portion of the pore spaces is occupant by gas (Cole, 1969).

### **2.3 CO<sub>2</sub> Gas Injection**

Gas injection is one of the oldest EOR methods introduced to improve oil recovery. Gas injection are usually regarded as a tertiary recovery method, however in certain cases, gas injection is use as secondary recovery. By general, the gases that are widely applied in EOR are carbon dioxide (CO<sub>2</sub>), hydrocarbon gases, and nitrogen (N<sub>2</sub>) gas. The most common one is CO<sub>2</sub> due to its high solubility in water and hydrocarbon and abundant in nature. The process could be miscible or immiscible depending on the most crucial parameter in determining the miscibility of the injected gas i.e. the Minimum Miscibility Pressure (MMP). MMP is the minimum required pressure at which the injected gas becomes miscible with the reservoir oil. If the MMP is higher than the current reservoir pressure, it might not be economical to implement miscible gas flooding due to large compression requirement. Technically the maximum pressure that we can inject the gas is determined by the reservoir fracturing pressure. When gas is injected at the MMP and above, the process will be miscible gas flooding. When gas is injected below the MMP, the process will be immiscible gas

flooding. The purpose of immiscible gas flooding is normally to maintain the reservoir pressure.

In the miscible displacement, the injected gas will completely dissolve the reservoir oil through first contact (FCM) or multiple contacts (MCM). In first contact miscibility (FCM), CO<sub>2</sub> is directly miscible with oil when in contact. However this is not always the case, multiple contacts of CO<sub>2</sub> and oil are required for mass exchange of the intermediate component of hydrocarbon through vaporizing, condensation or both. After several contacts and exchange of component between gas and oil, it will reach critical composition, thus cause miscibility. Oil composition is an important factor affecting miscibility, a high percentage of intermediate hydrocarbons (C<sub>5</sub> through C<sub>12</sub>) is beneficial (Martin & Taber, 1992). When, oil and CO<sub>2</sub> are miscible, the interfacial tension (IFT) will be reduce until 85% and thus eliminating the forces that cause oil retention in the rock matrix and improve sweep efficiency (Ghedan, 2009). Miscibility also will cause oil swelling which reduce the viscosity of the oil. Thus, the mobility of oil will significantly increase and also swollen oil droplet (bypassed oil by waterflooding) will force water out of pore spaces until the oil is mobile. Swelling factor increase with pressure and decrease with temperature and density (Mangalsingh & Jagai, 1996).

The limitations of applying gas injection EOR are highly dependent on the type of gas to be injected into the reservoir and the reservoir temperature and pressure. Solubility of gas in oil decreased with increasing temperature (>150°C) and reduced API gravity (Mangalsingh & Jagai, 1996). Source and supply of the gas must be adequate and continuous to supplement the injection requirements. Applications of gas EOR requires the current reservoir pressure be higher than the MMP to secure the miscibility of the injected gas and the remaining oil which made depth as an important criterion (Martin & Taber, 1992). The major drawback of CO<sub>2</sub> application is its very high mobility ratio as CO<sub>2</sub> viscosity and density is very low. This will cause severe viscous fingering and early gas breakthrough which ultimately reduced displacement efficiency and cause high producing gas-oil ratio. CO<sub>2</sub> injection also cause poor areal displacement recovery due



to its low density in which the gas will move upward which left the residual oil underneath untouched.

CO<sub>2</sub> injection also has the possibility to cause asphaltene precipitation which will clog the pores and reduces the permeability and might change the rock wettability (especially intermediate we rock). Asphaltene deposition are a severe problem for light rather than heavy oil although the heavy oil contain higher percentage of asphaltene (17%) compared to light oil (0.1%). This is due to composition of heavy oil which contain high resin and aromatic component which cause the lighter oil to have lower potential of asphaltene solubility. Rock wettability will become more oil-wet when asphaltene content in crude oil exceeds 4.6 wt % (Ghedan, 2009). Injection of CO<sub>2</sub> can develop corrosion problems to the producing facility as the gas exhibits acidic behavior. Corrosion inhibitors are usually injected to minimize the corrosion, but will have a strong impact on the economics.

## **2.4 Water-Alternated-Gas (WAG)**

Considering its successful applications in the North Sea, US and Canada oil fields, WAG injection can be regarded as a matured technology. Both miscible and immiscible injections have been practiced worldwide. In most cases, WAG has been implemented as tertiary miscible injection projects. Incremental recovery by application of WAG is reported in the range of 5 to 10% of original oil in place (OOIP) (Ramachandran, *et al*, 2010). Availability of hydrocarbon gas and limited storage facilities necessitated gas injection projects which were also aimed at improving recovery. It was reported that it may be difficult to distinguish between miscible and immiscible WAG process. In the life of oil production, the process can fluctuate between miscible & immiscible (Lake, 2008).

WAG injection is an oil recovery method initially aimed to improve sweep efficiency during gas injection. In some recent applications produced hydrocarbon gas has been re-injected in water injection wells with the aim of improving oil recovery and pressure maintenance. Oil recovery by WAG has been attributed to contact of unswept zones, especially recovery of attic or cellar oil by exploiting the segregation of gas to the top or

accumulating of water towards the bottom and also better overall sweep efficiency is obtained by gas displacement at low permeability layer (Sanchez, 1999). Since the residual oil after gas flooding is normally lower than the residual oil after water flooding, and three-phase zones may obtain lower remaining oil saturation, WAG has potential for increased microscopic displacement efficiency. WAG injection, thus, can lead to improved oil recovery by combining better mobility control and contacting unswept zones, and also leading to improved microscopic displacement. To displace oil effectively, the flood front has to be stabilize. This influenced by rock type, injection strategy (water and gas injector position), miscible/immiscible gas, and well spacing (Lake, 2008). WAG ratio is also an important factor. The optimum WAG ratio was 1:4 (Mangalsingh & Jagai, 1996).

Injecting gas with water alternately also reduce the mobility of gas. It reduces the breakthrough time of gas and viscous fingering. Thus, increase the oil-CO<sub>2</sub> contact time. WAG. This resulted in low producing GOR as indicated by several case study in which GOR for continuous gas flooding is high as 2000 cc where as for WAG flooding it was below 500 cc. lower pore volume requirement is also highlighted as WAG application advantage (Mangalsingh & Jagai, 1996).

The limitation of this method is oil trapping due to water injected reduce the contact of oil and CO<sub>2</sub>. Laboratory studies have concluded that rock wettability strongly affects the trapping mechanism of oil by water. Oil trapping happen more severe in water-wet reservoir which some cases show more than 45% of the waterflood residual oil was trapped (Ghedan, 2009)

## **2.5 Chemical Flooding**

Chemical flooding involves the injection of specific liquid chemicals that effectively displaces oil because of their phase-behavior properties. Methods include utilisation of polymers (P), surfactants (S), alkaline (A) chemicals and their combination as in AS, SP and ASP. The displacing fluid or micellar solution has limited solubility with oil and designed to lower the IFT between the displacing fluid and oil resulted in minimal

trapping. Favorable mobility of the micellar solution also contributes to efficient displacement (Green & Willhite, 1998). From worldwide experience, the typical incremental recovery from a Chemical EOR ranges between 10 to 25% of Original Oil in Place (OOIP).

## **2.6 Foam-Assisted WAG (FAWAG)**

Foam-Assisted Water Alternating Gas (FAWAG) process has given tremendous improvement in recovery by improving sweep efficiency during gas injection and gas shut-off. Even less GOR was seen in most of the process. Foam has increased mobility control of gas flow and has come up with a new method for improvement of well flow.

FAWAG is usually introduced in reservoirs with WAG process already in use. It is observed that during WAG process, initial cycle is efficient than later. In addition, due to the establishment of trapped gas saturation in the area after first gas injection and mass exchange reduction between oil and gas in the second gas injection period, gas breakthrough is expected to arrive earlier

The FAWAG technique implemented to Snorre Field in Norway has become the largest world's application in four pilot projects in the different parts of the field. The FAWAG project was commenced in 1997 on the Central Fault Block (CFB) of the Snorre Field (Blaker, *et al.*, 2002). Snorre is one of the major oil fields on the Norwegian Continental Shelf in the North Sea. The Snorre Field is used as a reference to conduct the FAWAG project in Field A West. The Snorre Field was initially developed with water injection as the main drive mechanism and came on stream in 1992. One of the first measures taken to increase production was implementation of a downdip WAG pilot in the CFB. The FAWAG project has been a full-scale field demonstration of the use of foam to improve gas sweep efficiency during water-alternating-gas (WAG) injection (Skauge *et.al*, 2002).

In the mid-1996, a foam treatment was performed on production well P18 located in the Central Fault Block of the Snorre Field. The P18 well had suffered high gas oil ratio (GOR) due to premature gas breakthrough. The purpose of the field pilot was to reduce the production GOR in P18 (Skauge *et.al*, 2002).

The foam treatment was performed in 8 Darcy and 7.2 m thick sand layer of the Statfjord formation. The treatment was performed using surfactant alternating gas injection (2 cycles) and co- injection and the high permeable layer to be treated was mechanically isolated during the injection.

32 tons of surfactant was used divided with 8 tons on each surfactant alternating gas cycle and 16 tons on the co-injection; the surfactant concentration was either 1 or 2 wt%. Pressure build-up data during injection and tracer analyses during production after treatment was used to evaluate foam generation. It was concluded that the foam generation during SAG injection was limited, but the co-injection generated strong foam. After foam treatment the plug isolating in the high-permeable streak was removed. A 50% reduction in GOR was observed in P18 for more than two months (Skauge et.al, 2002).

## **2.7 Surfactant**

The term surfactant finds its origin from the term "surface active agent". Surfactants are organic compounds that have an amphipathic nature, meaning they contain both a hydrophobic group (their tail) and hydrophilic group (their head) (Schramm *et al.*, 2000). The surfactant-brine-oil phase behavior is strongly affected by the salinity of the brine. For low brine salinities, a typical surfactant flood will exhibit good aqueous phase solubility and poor oil-phase solubility. For high brine salinities, the surfactant solubility decreased in the aqueous phase by electrostatic forces (Lake *et al.*, 1989). Surfactant stability is also known to be sensitive to high temperature and high salinity (Green & Willhite, 1998).

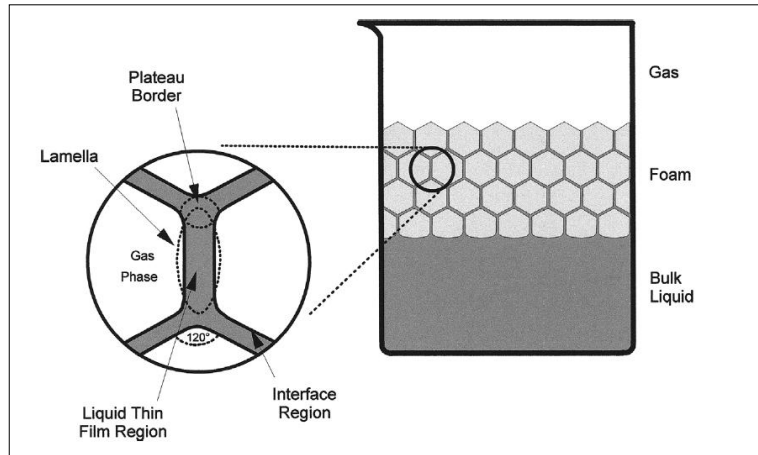
A surfactant is briefly defined as a material that can greatly reduce the surface tension of a liquid (usually water) when used in very low concentrations. The concentration at which micelles are formed is called the critical micelle concentration (CMC). When surfactant concentration is lower than CMC, the interfacial tension will decrease significantly with increasing surfactant concentration. After the surfactant concentration exceeds CMC, however, there will be only small changes in the value of interfacial

tension with increasing surfactant concentration. Though the interfacial tension does not change much with the changing of the surfactant concentration after it exceeds CMC, the higher surfactant concentration will result in more micelles. Micelles can solubilize non-polar materials by enclosing them in their hydrophobic (Green & Willhite, 1998).

Applying surfactant flooding at high salinity conditions requires a tailoring of the surfactant system with regard to optimizing physicochemical properties (e.g., interfacial tension toward oil phase, dynamic retention, and temperature stability). This can in some cases be difficult, time-consuming, and uneconomical. In contrast, low salinity environments open up a route to a wider portfolio of more commercially available and low-cost surfactant systems. At lower salinities, there is an increased possibility for surfactants that meet the current environmental and safety regulations. In the past decade, an extensive effort has been directed at low salinity water flooding, (Morrow *et al.*, 1998). So, from the previous study, it has been showed that a great potential of using surfactant at low saline environments.

## **2.8 Foam**

Foams are special kind of colloidal dispersion: one in which a gas is dispersed in a continuous liquid phase (Schramm, 1994). The general foam structure is contained on the bottom by the bulk liquid and on the upper part is a second bulk phase, which is gas. The gas phase is separated from the thin-liquid film, by a two dimensional interface. Lamella is defined as the region that encompasses the thin film, the two interfaces on the either side of the thin film, and part of the junction to other lamellae as depicted in Figure 1 (Schramm, 1994). The connection of three lamellae, at angle of  $120^\circ$ , is called the plateau border.



**Figure 1 : generalized foam systems (Schramm, 1994)**

The foam structure can be formed in a liquid if bubbles of gas are injected faster than the liquid between bubbles can drain away. When two or more foam come together, coalescence occurs very rapidly, without detectable flattening of the interface between them; that is, there is no thin-film persistence (Schramm, 1994). The adsorption of the surfactant or foaming agent at the gas-liquid interface enhances thin-film persistence. Gas phase, liquid phase and a surfactant/foaming agent are the factors contributing towards the foam persistence. Foaming agent or surfactants are macromolecules, or finely divided solids. That is used in the petroleum industry as a surface tension reducer and aids the formation of the increased interfacial area with less mechanical energy input. According to Schramm (1994), foaming agents may be needed to form a protective film at the bubble surfaces that acts to prevent coalescence with other bubbles. Foam stability or persistence can be considered as two different processes: film thinning and coalescence.

Film thinning is the process where the bubbles come closely together, but there is no change in surface area. Coalescence is the process of bubbles combined together to be a single droplet, larger bubbles, thus reducing the total surface area. The stability of foam is defined by few factors involving bulk solution and interfacial properties:

- Gravity drainage
- Capillary suction

- Surface elasticity
- Viscosity (bulk and surface)
- Electric double-layer repulsion
- Dispersion force attraction

Foam has been extensively used in improved and enhanced oil recovery processes in the petroleum industry over decades (Al-Mossawy, *et.al*, 2011). The main use of foam in petroleum industry is to control gas mobility of oil reservoir during the application of gas injection or water-alternating-gas (WAG) process. The high mobility and low density of the gas allows gas to flow in channels through high permeability zones of the reservoir and to rise to the top of the reservoir by gravity segregation (Al-Mossawy, *et.al*, 2011). This mechanism leads to the decline of the sweep efficiency and consequently increases the residual oil in the reservoir. Foam is used in petroleum industry to control gas mobility and improving sweep efficiency by increasing the effective viscosity and decreasing the relative permeability of the gas. Foam is easily form in high permeability zones, so the foam will redirect the gas to the lower permeability and smaller pore zones where residual oil is most abundant. Thus foam able to solve a thief zone or override problem encountered before (Turta & Singhal, 2002). Another use of the foam is for gas shut off to reduce the gas/oil ratio (GOR) at the production wells (Al-Mossawy, *et.al*, 2011).

Foam injection project requires comprehensive research & developments and reservoir simulation studies. The operating parameters that should be investigated through laboratory experiment are;- formulation and concentration optimisation of foaming agent or surfactant, pressure gradient required for stable foam flow, and injection strategy: either pre-prepared foam before injection, or co-injection of surfactant solution and gas, or surfactant solution-alternating-gas (SAG) injection (Al-Mossawy, *et.al*, 2011). The simulation of reservoir is required to obtain the locations of the injection wells, optimise the injection pressure, volumes of gas and surfactant solution, and number of cycles and period of each cycle if the SAG injection option is chosen.

## 2.9 Low Saline Water

Low Salinity flooding is an emerging technology to improve waterflood oil recovery for both sandstone and carbonate reservoirs. Extensive laboratory experiments have been done to investigate the effect of low salinity. However, the field experience using change in brine salinity to improve oil recovery is yet very limited and the mechanisms suggested explaining low salinity effect (LSE) is very diverse (Skauge, 2013).

Most of the literatures on low salinity effect on improved oil recovery refer to the experimental works done by Tang and Morrow (1999) and also by Lager (2008).

- Fines Migration: fines were being eluted during low salinity waterfloods on Berea core samples. They associated it with clay production, mainly Kaolinite in effluents. Tang and Morrow (1999) suggested a theory based on the release of mixed-wet clay particles from pores. During aging, clay fines are partly in contact and exposed to crude oil, and the fines are then mixed-wet particles. The production of oil droplets on these clays would contribute in changing the system to a more water wet system, since the fines migration resulted in exposure of the underlying surfaces that lead to an increase in water-wetness of the system. When high salinity brine is present, clays are undistributed and retain their oil wet nature leading to poorer displacement efficiency (Lager *et al.*, 2006). When the clay particles come in contact with low salinity water, the clay particles will detach from the pore surface. Fines migration related to permeability reduction and formation damage.

Skauge *et al.* (2008) proposed a new explanation of partial mobilization of fines, where the released clay particles will block pore throats and divert the flow of low salinity brine into non-swept pores. This will increase the microscopic sweep efficiency and increase the total oil recovery.

- pH effects: Tang and Morrow (1999) observed a pH increase by low salinity injection on Berea sandstones. The pH increase could be explained by carbonate dissolution and cation exchanges (Lager *et al.*, 2006). The dissolution reactions



are dependent on the amount of carbonate present in the rock. During the dissolution of carbonate, an excess of  $\text{OH}^-$  will give increased pH. Cation exchange will occur between clay minerals and the invading low salinity brine. An exchange of  $\text{H}^+$  in the liquid phase with cation previously adsorbed at the mineral surface, will lead to a decrease of  $\text{H}^+$  concentration inside the liquid phase. This could also result in a pH increase. The IFT between the reservoir oil and water is reduced by low salinity water injection (Morrow *et al.*, 1998) like it is by alkaline flooding.

### CHAPTER 3: EXPERIMENTAL PROCEDURES AND MATERIALS

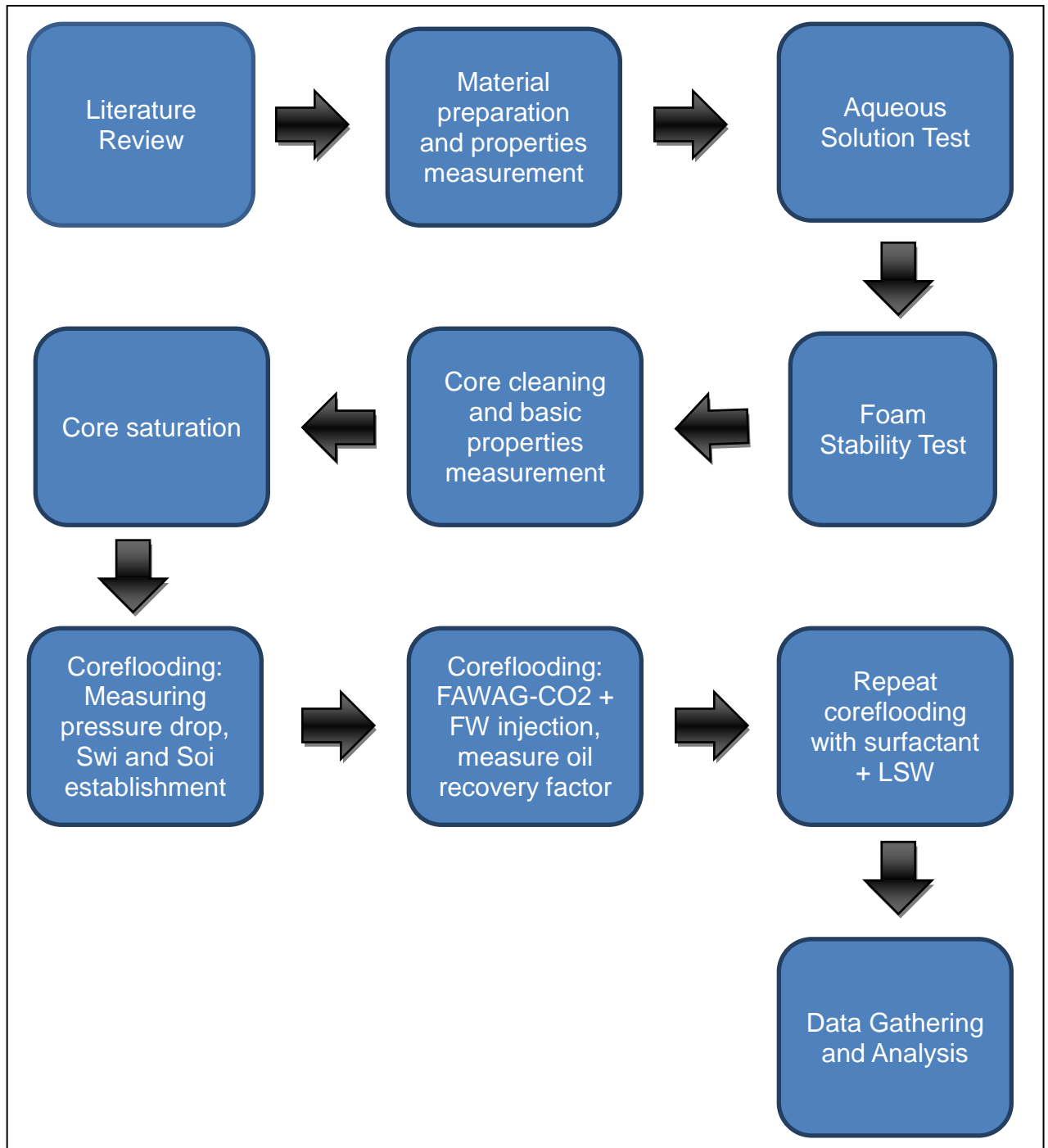


Figure 2 : Brief Research Project Process

### **3.1 Research Materials**

#### **1. Surfactant**

- i. Sodium Dodecyl Sulphate (SDS)
- ii. Sodium Lauryl Sulphate (SLS)

#### **2. Brine**

In this research, two type of brine will be used:

- i. Formation brine – brine obtained for the field. Formation brine will be used to establish connate water saturation in the core. The brine salinity will be 30000 ppm.
- ii. Injection brine – this brine will be prepared by mixing distilled water with Sodium Chloride, NaCl with different salinity. 1000 ppm, 2000 ppm, and 5000 ppm of brine salinity will be prepared.

#### **3. Gas**

Only CO<sub>2</sub> will be used. The gas only will be use during coreflooding process.

#### **4. Oil**

Crude oil sample obtained from Dulang field, in offshore Terengganu.

#### **5. Core Plugs**

About 50% of the world's petroleum reservoirs are found in sandstones rock and sandstones are usually non-fractured and have a high permeability. This research will be using Berea sandstone core samples.

### **3.2. Brine Preparation**

Brine will be made artificially by dissolving desired amount of salts in distilled water. Two different type of brine will be produced which is formation water and low saline water. High amount of salt will be dissolved to make formation water to

reach salinity of about 30000 ppm. FW will be used for saturation and establishing connate water purposes in core plugs and also in conventional core flooding. While, low saline water (LSW) required much smaller amount of salt to reach 1000 ppm, 2000 ppm and 5000 ppm of salinity. LSW will be used for wettability alteration and the other tests. One stock solution of 50000 ppm brine is prepared by dissolving 50g of NaCl in 1 litres of distilled water. To prepare the FW and LSW, the stock solution will be diluted with distilled water measured from this calculation:

$$M_1 V_1 = M_2 V_2 \dots\dots\dots \text{Equation 1}$$

where:

$M_1$  = Original concentration (eg: 50000 ppm)

$V_1$  = Original Volume (eg: 500 ml)

$M_2$  = Final Concentration

$V_2$  = Final Volume

### 3.3 Aqueous Solution Test

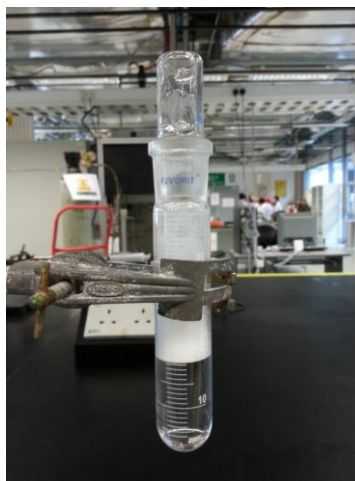
This test will be conducted to check the compatibility of surfactant with brine of different salinity. Aqueous stability refers to a surfactant that dissolves in brine and forms a clear solution. A surfactant must be chemically stable in the presence of salt ions to pass this test. When a surfactant does not pass aqueous stability, it precipitates or separates from solution. This separation may cause problems during the core flood stage by plugging in the pores, or even worse in the field, by increasing its absorption to the rock and increasing production costs.

5 ml of 2 wt% of surfactant solution and 5 ml brine of different salinity will be mixed together in a test tube until it forms a clear solution. The solutions are left in the oven at 80 °C. Observation will be made at day 1, day 3 and day 5.

### 3.4 Foam Stability Test

This test is done to determine the stability of foam and compare which surfactant performed the best at different brine salinity. Foam stability tests are a simple and quick indication of the foaming capabilities of a surfactant formulation when mixed brine of different salinity. Surfactant screening is an important task in the processes that involve the use of foam. Several screening methods have been developed, including static tests, Ross Miles test and porous media tests. However, they are neither dependable nor standard. For this project, static bottle test is used due to equipment and time limitations. This test requires an inexpensive setup and simple experimental procedure.

In a calibrated 50 ml test tube, aqueous solution consisting of 10 ml of 2 wt% surfactant solution and 10 ml brine are mixed. The concentration are kept constant as from the previous works done by Zhong, *et al.* (1998), it appears that surfactant concentration may not be an important factor in affecting the foam stability. The test tubes are closed to prevent evaporation during heating to reservoir temperature. The test tube will be left in the oven at 80 °C for 15 minutes for temperature equilibration. Then, the test tubes are shaken with equal intensity for 1 minutes resulting in the formation of a foam column. All test tubes are shaken with the same intensity to improve reproducibility of the test and reduce operational error. The foam height will be noted for every 5 minutes until all foam is deteriorate. The test is repeated using different brine salinity.



**Figure 3: Test setup and foam formed by surfactant solution**

### 3.5 Core Sample Preparation

Before any test is conducted, the core plug have to be make sure clear of any contaminant such as salt, oil or any other organic materials.

#### 3.5.1 Core Cleaning

All cores will be cleaned by using soxhlet extractor (Figure 4) with toluene. Toluene will displace the oil and the organic materials in the core. The toluene will be heated up and the steam created will cleaned the core before condense back by the flowing water bath. The core will be put there for 3 to 5 days. Then, it will be dried at 100 °C in the oven for two days. After drying, the core dimensions, and weight will be measured.



**Figure 4: Core cleaning by Soxhlet Extractor**

### 3.5.2 Basic Properties Measurement

The porosity, permeability and pore volume of the dried cylindrical cores is measured using PoroPerm Coval 30 (Figure 5). The PoroPerm instrument is a permeameter and porosimeter used to determine the properties of plug sized core samples at 400 psi confining pressure. The measurement is based on the unsteady state method (pressure falloff) whereas the pore volume is determined using the Boyle's law technique. The gas that is used for the measurement is helium due to its inert properties. Before plugging the core into the core holder, the length and diameter of the core have to be measure first using a digital caliper. The data is entered into Applilab, the PoroPerm software. The equipment is run through the software.

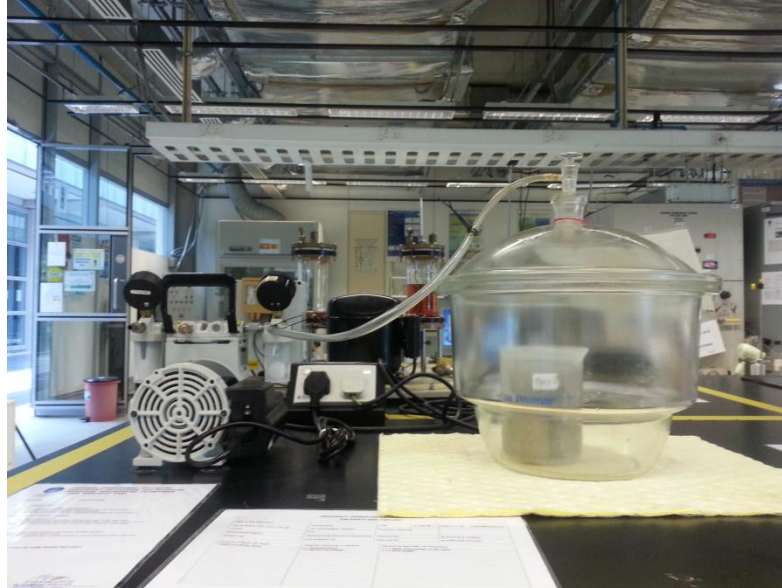


**Figure 5: PoroPerm Coval 30 with the computer that run it**

### 3.5.3 Core Saturation establishment

The dried and cleaned core is put into a beaker containing the designated formation water which in this project, the formation water salinity is 30000 ppm (only contain Sodium Chloride, NaCl). The beaker then put into a dessicator connected to a pump (Figure 6). The pump will created a vacuum inside the desiccator which will allow the

formation water to fill the pore spaces inside the core. The core will be left there for 7 days.



**Figure 6: Dessicator connected to a pump**

### **3.6 FAWAG + FW or LSW Core Flooding**

Two set of coreflooding experiment will be done. For the first set, FAWAG-CO<sub>2</sub> is tested with FW, while for the second set, FAWAG-CO<sub>2</sub> is tested with LSW

#### **3.6.1 Connate water saturation, $S_{wc}$ and initial oil saturation, $S_{oi}$ establishment**

The saturated core sample is placed into the core holder. The formation brine, Dulang crude oil and surfactant are pumped into separate floating piston accumulators. The confining pressure inside the core holder is set to 2500 psia while the temperature is set at 98 °C. The coreflooding equipment that is being used is TEMCO RPS-800-10000 HTHP Relative Permeability Test System (Figure 8). The test condition for the equipment can be up to 10000 psig flowing pressure, and up 10000 psig overburden pressure and temperature up to 177 °C (350 °F). Formation brine will first injected into



the core at an injection pressure of 1700 psig and injection rate of 1 cc/min to make sure the flow is steady state and the core is 100 % saturated with the formation brine. The injection of the formation brine also helps to determine the absolute permeability of the core. This is followed by the injection of Dulang crude oil into the brine saturated core at similar injection rate and pressure. The crude will be injected until no more water is produced which indicates the connate water saturation is established. The volume of water produced is the initial oil saturation. The following is the equation to determine  $S_{wc}$  and  $S_{oi}$ .

$$S_{wc} = \frac{\text{Pore Volume (cc)} - \text{Volume of water produced (cc)}}{\text{Pore Volume}} \dots\dots\dots \text{Equation 2}$$

$$S_{oi} = 1 - S_{wc} \dots\dots\dots \text{Equation 3}$$

### 3.6.2 Secondary recovery: Waterflooding

After the connate water and initial oil saturation of the core is established, waterflooding can be directly started. This project is aiming to investigate the performance of FAWAG as an effective tertiary recovery mechanism, so waterflooding is required. Formation brine (30000 ppm) will be injected at a similar injection pressure and rate and also temperature. The formation brine will be injected until no further oil is produced or the differential pressure (DP) versus time (t) chart is stabilized. The chart can be monitored from Smart-Flood 4, software that controls the equipment. The volume of brine and oil produced will be measured and recorded as a function of time. Oil recovery factor also will be calculated.

$$\text{Oil Recovery Factor (\%)} = \frac{\text{Volume of oil produced (cc)}}{\text{Original oil in place, OOIP (cc)}} \times 100\% \dots\dots\dots \text{Equation 4}$$

### 3.6.3 Tertiary recovery: FAWAG-CO<sub>2</sub> + FW

After the waterflooding, the formation brine is first removed from the accumulators and replaced by pure carbon dioxide, CO<sub>2</sub> as the number of accumulators available is limited. Then, the surfactant (2.5 wt% SDS + 30000 ppm brine) is injected at similar condition as the waterflooding. The surfactant is injected until the DP vs t chart is

stabilized. Immediately after that, CO<sub>2</sub> is injected. Surfactant will be injected again and followed by CO<sub>2</sub>. Similar as waterflooding, volume of oil and brine produced at every 15 minutes will be measured and recorded at each stage of injection until the injection is stop.

#### 3.6.4 Tertiary recovery: FAWAG-CO<sub>2</sub> + LSW

The procedure is similar as FAWAG-CO<sub>2</sub> + FW, only the surfactant injected is changed which in this case the surfactant used is 2.5 wt% SDS + 5000 ppm brine.

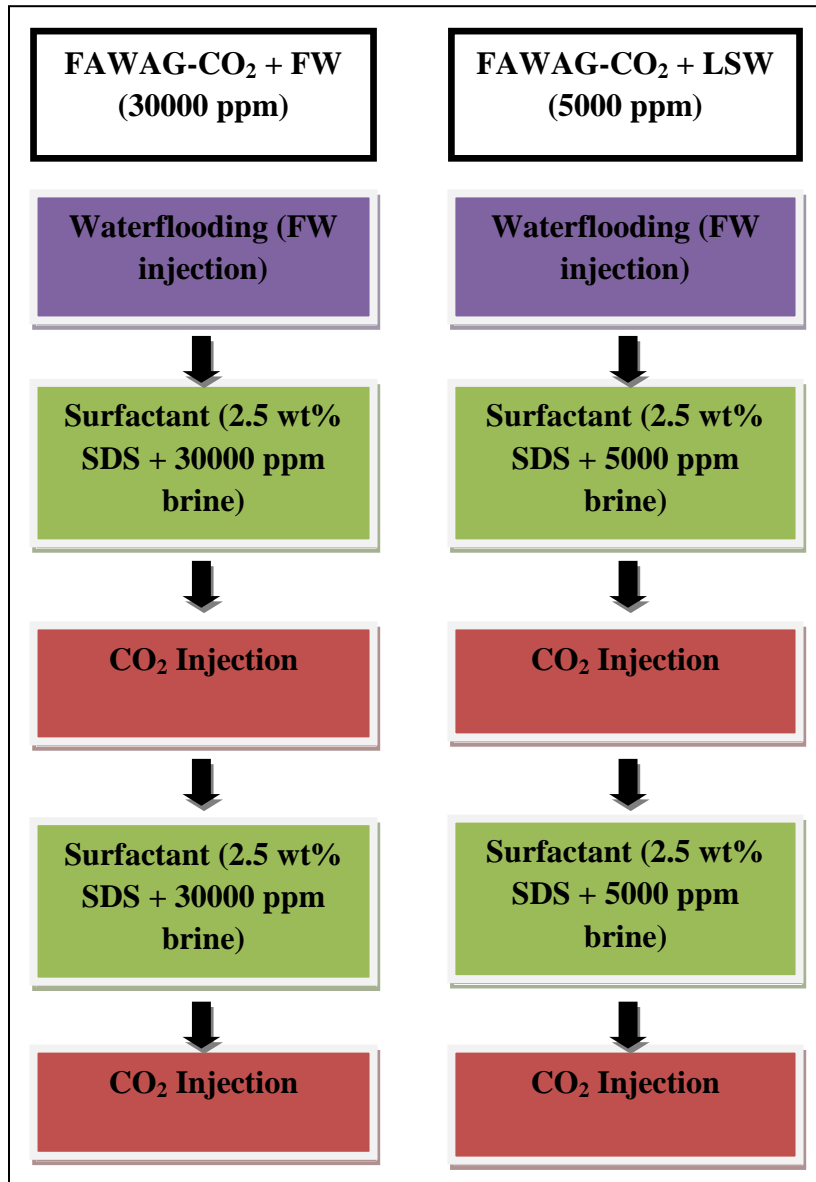


Figure 7: Conventional FAWAG-CO<sub>2</sub> + FW and FAWAG-CO<sub>2</sub>+LSW coreflooding process

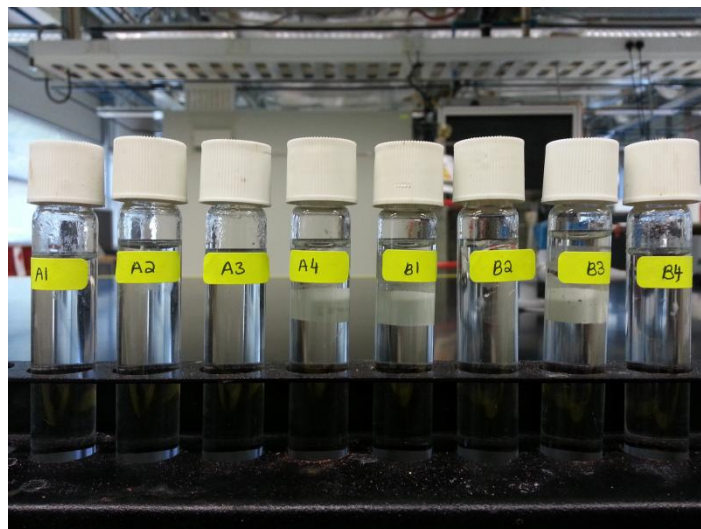


**Figure 8: TEMCO RPS-800-10000 HTHP Relative Permeability Test System**

## **CHAPTER 4: RESULTS AND DISCUSSION**

### **4.1 Aqueous Solution Test**

This test is to determine whether the surfactant solution and the brine solution can mix well without creating a phase separation. The samples of all possible combination are kept in oven maintained at 80°C. The observation is taken at day 1, day 3 and day 5. As shown in Figure 9, all combination of surfactant solution (2 wt% SDS solution and 2 wt% SLS solution) and brine with different salinity (1000 ppm, 2000 ppm, 5000 ppm and 30,00 ppm) are in clear solution without any visible separation as shown in Figure 9.



**Figure 9 : Several samples with different combination of surfactant solution and brine. A1 (SLS + 1000 ppm), A2 (SLS + 2000 ppm), A3 (SLS + 5000 ppm), A4 (SLS + 30000 ppm), B1 (SDS + 1000 ppm), B2 (SDS + 2000 ppm), B3 (SDS + 5000 ppm), B4 (SDS + 30000 ppm)**

#### 4.2 Foam Stability Test

This test is aimed to determine the effect of brine salinity on foam stability. The results are shown in Table 1 and Table 2.

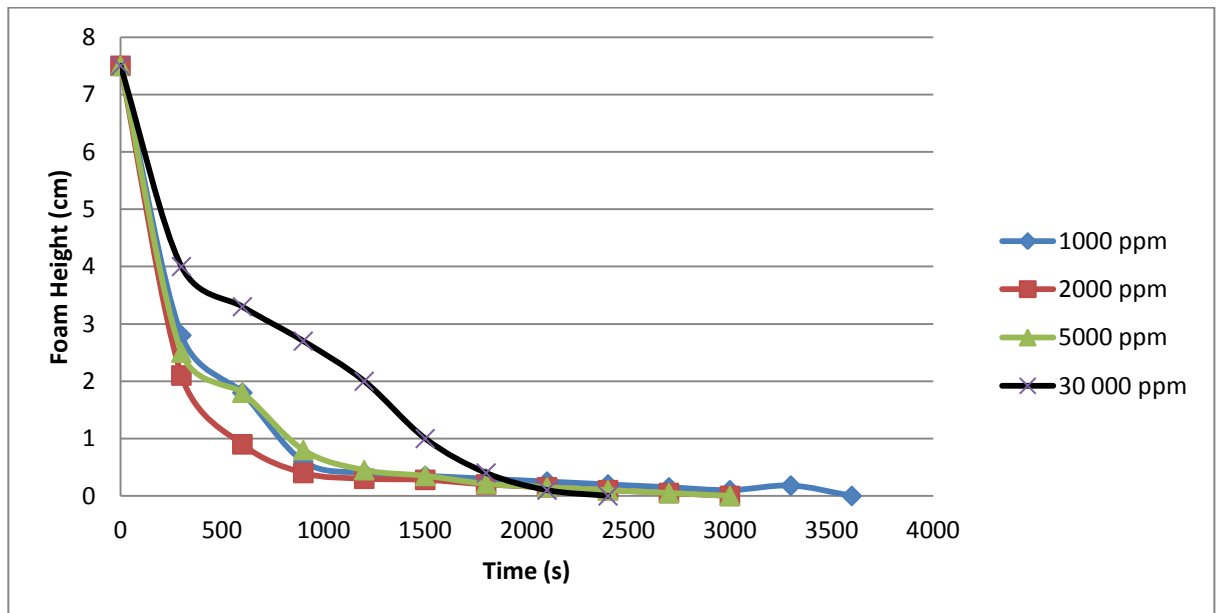
**Table 1: Summary of Bottle Test Results (Without Oil) for SLS solution: Foam Height vs. Time**

<b>Sodium Lauryl Sulphate (SLS) concentration : 2 wt %</b>				
<b>Minutes</b>	<b>Foam Height (cm)</b>			
	<b>1000 ppm</b>	<b>2000 ppm</b>	<b>5000 ppm</b>	<b>30 000 ppm</b>
0	7.50	7.50	7.50	7.50
5	2.80	2.10	2.50	4.00
10	1.80	0.90	1.80	3.30
15	0.60	0.40	0.80	2.70
20	0.40	0.30	0.45	2.00
25	0.35	0.28	0.35	1.00
30	0.30	0.20	0.21	0.40
35	0.25	0.15	0.15	0.10
40	0.20	0.10	0.10	0.00
45	0.15	0.05	0.05	
50	0.1	0.00	0.00	
55	0.18			
60	0.00			

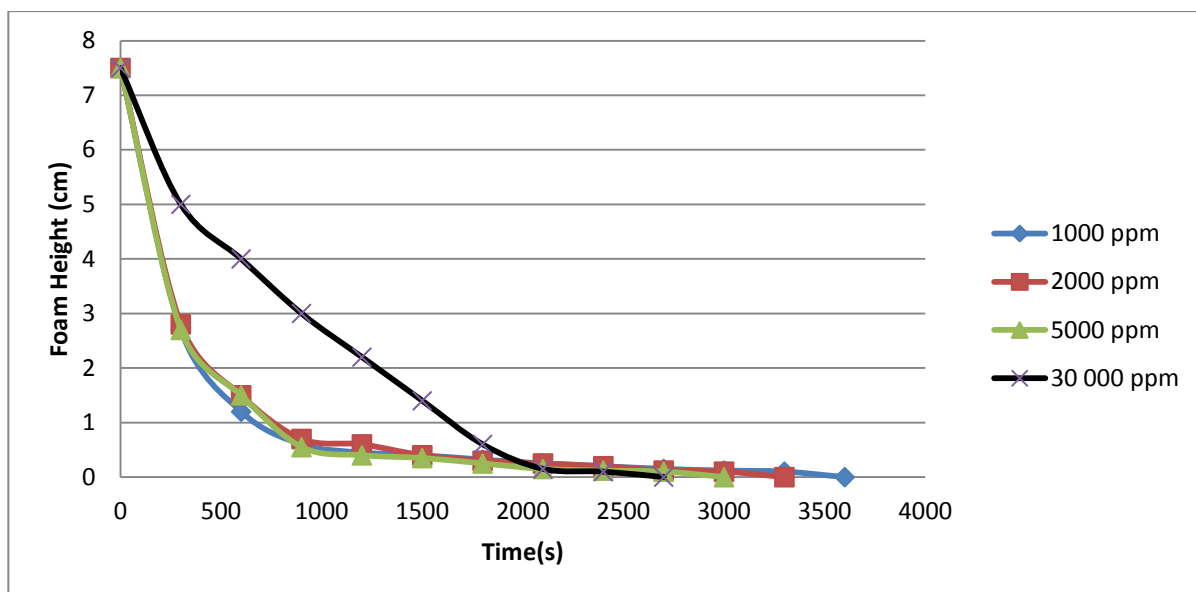
**Table 2: Summary of Bottle Test Results (Without Oil) for SDS solution: Foam Height vs. Time**

Sodium Dodecyl Sulphate (SDS) concentration : 2 wt %				
Minutes	Foam Height (cm)			
	1000 ppm	2000 ppm	5000 ppm	30 000 ppm
0	7.50	7.50	7.50	7.50
5	2.70	2.80	2.70	5.00
10	1.20	1.50	1.50	4.00
15	0.60	0.70	0.55	3.00
20	0.45	0.60	0.40	2.20
25	0.40	0.40	0.35	1.40
30	0.32	0.30	0.25	0.60
35	0.25	0.25	0.15	0.15
40	0.20	0.20	0.12	0.10
45	0.15	0.12	0.10	0.00
50	0.12	0.10	0.00	
55	0.10	0.00		
60	0.00			

Based on the table above, Figure 10 and Figure 11 is plotted to compare the test results for both surfactant solution.



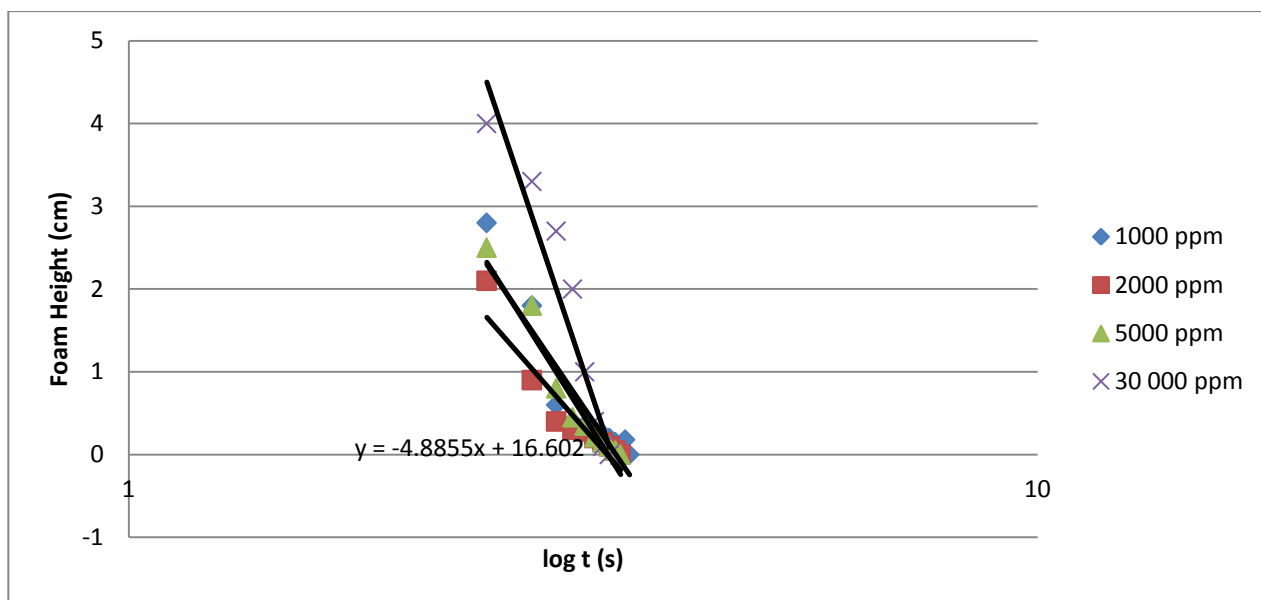
**Figure 10: Foam Height vs Time plot for SLS surfactant solution**



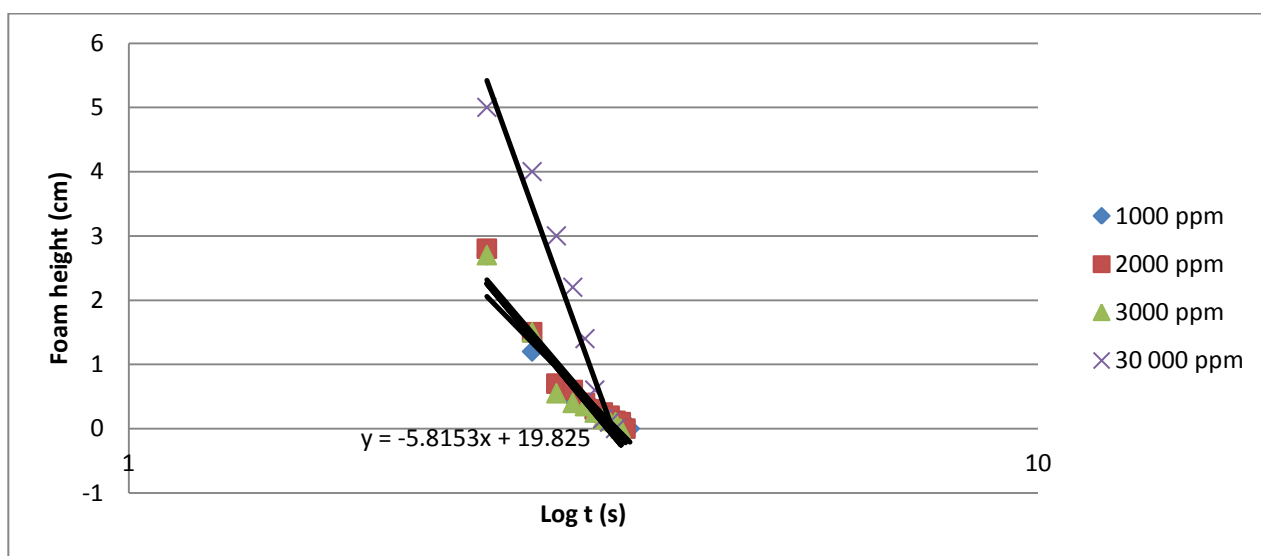
**Figure 11: Foam Height vs Time plot for SDS surfactant solution**

From both Figure 10 and Figure 11, it can be clearly seen that the aqueous solution of surfactant and 3000 ppm brine have the highest stability for the first 35 minutes. However, the foam created from this solution deteriorates faster which about 15 minutes earlier if compared to the surfactant solution with 1000 ppm brine. The foam from other surfactant solutions are performed much less the same, only that the surfactant solution mixed with 1000 ppm brine have a higher retention time by 5 minutes.

Figure 12 and Figure 13 is plotted to compare the foam performance formed by SLS and SDS solution.



**Figure 12: Foam Height vs Log t plotted on semi-log chart for SLS solution**



**Figure 13: Foam height vs Log t plotted on semi-log chart for SDS solution**

From Figure 12 and Figure 13, the performance of foam formed by both surfactant solutions are almost the same. However, from the gradient of the linear line of 30000 ppm plot, the SDS solution performed much better than the SLS solution which has a higher foam deterioration rate.

No difference is observed between the size of different foams, and no significant difference is observed in foam forming ability of the different surfactants. From the results shown in Table 1 and Table 2 and Figure 10 to Figure 13, it can be concluded that for this preliminary test, SDS solution has a better foam and can retain longer in a lower salinity brine.

### 4.3 Basic Properties Measurement

2 Berea sandstone core is obtained. The Berea sandstone cores are cleaned and dried in the oven. Core 1 is labeled as B-1 while Core 2 is labeled as B-2. The cores properties are tested with PoroPerm at temperature of 26 °C and humidity of 65 %. The properties of the cores are as in Table 3.

**Table 3: Properties of the Berea core samples**

Sample ID	Length (mm)	Diameter (mm)	Weight (g)	Conf. Pressure (nsig)	Porosity (%)	Pore Vol. (cc)	Bulk Vol. (cc)	Grain Vol. (cc)	Grain Density (g/cc)	Air Perm. (md)
B-1	72.06	37.70	169.558	400	15.072	17.088	80.439	68.316	2.482	107.255
B-2	70.06	38.22	174.666	400	14.377	16.521	80.379	68.823	2.538	57.732

### 4.4 Coreflooding Test

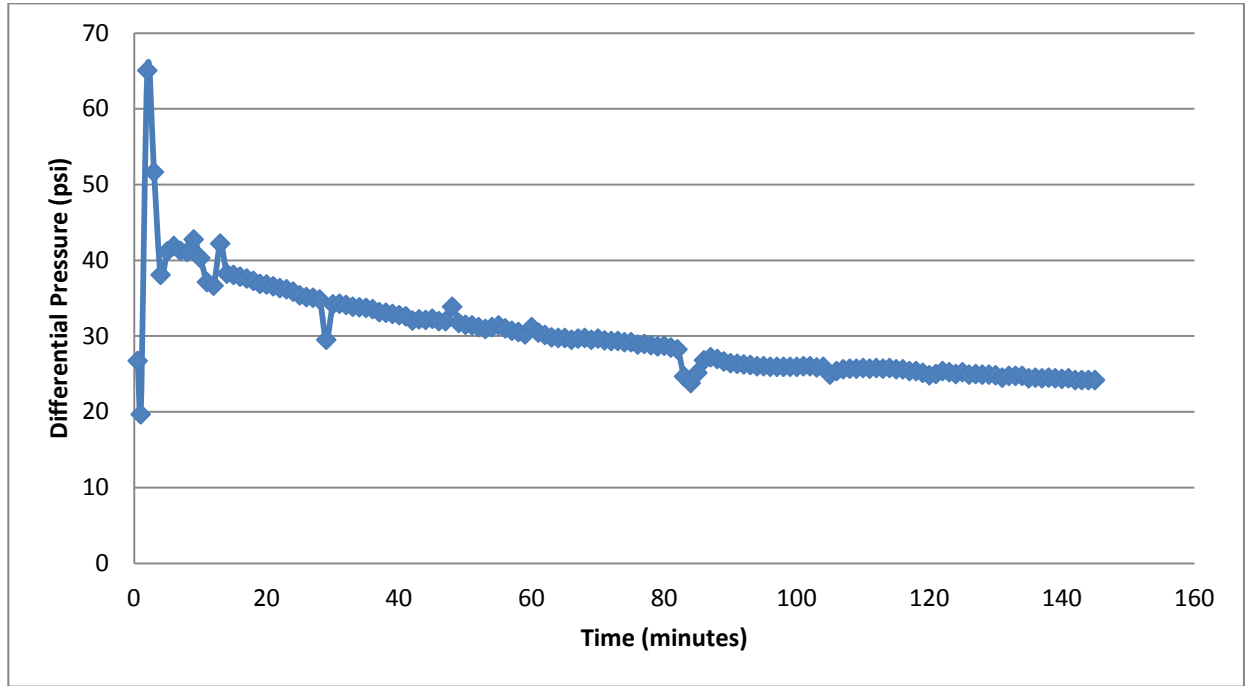
2 set of coreflooding experiment is done with only the surfactant formulation or the brine salinity is changing.

#### 4.4.1 FAWAG-CO<sub>2</sub> + FW (2.5wt% SDS in 30000 ppm brine)

For this set of experiment, core B-2 is used. The brine saturated core is coreflooded with formation brine and until the differential pressure versus time chart is stabilized as shown in Figure 14. The absolute permeability value is also determined which is 5.13 md which is considered as fair. The amount of brine produced as a function of time also consistent with the flow rate, 1 cc/min. This shows that the fluid flow is steady-state.



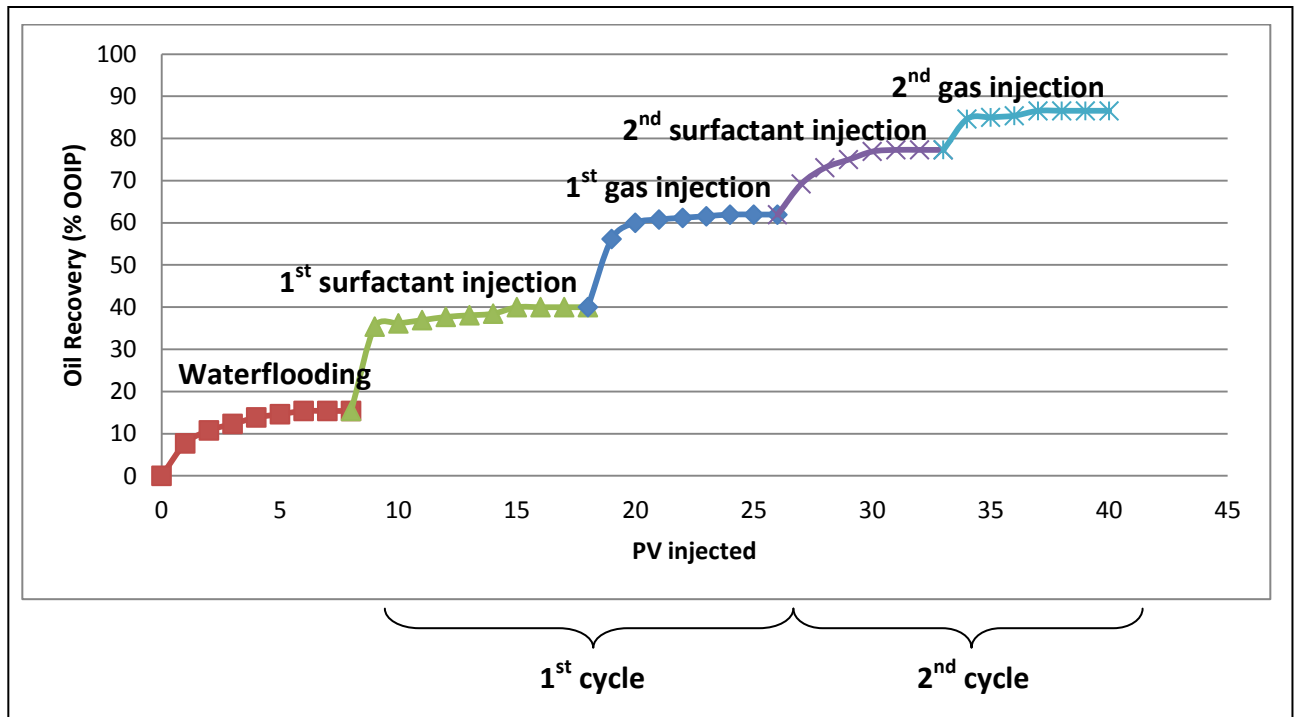
Oil is then injected into the core until no further water is produced. 13 cc of water is produced which is the value of the original oil in place. This means that the  $S_{oi}$  of the core is 0.79 and  $S_{wc}$  is 0.21



**Figure 14: Differential Pressure vs Time chart**

After the establishment of  $S_{oi}$  and  $S_{wc}$ , secondary recovery mechanism is started which is waterflooding. Formation brine with the salinity of 30 000 ppm is injected at an injection rate of 1 cc/min and injection pressure of 1700 psi at 98 °C. Waterflooding is continued until DP vs t chart is stabilized and no more oil is produced. After about 8 PV of FW is injected, only 2 cc of oil is produced or about 15.4 % of OOIP. Then, immediately after that, 1st cycle of FAWAG-CO<sub>2</sub> is started. 2.5wt% of SDS in 30000 ppm brine is first injected. There is significant increase of oil production compared to waterflooding. 40 % of the OOIP is produced in which the increment is about 24.6 % as shown in Figure 15 and Table 4. The increased recovery may due to emulsification of the crude and surfactant as some of the crude produced in the form of emulsions. IFT reduction also contributes to the increased recovery. CO<sub>2</sub> is then injected, further increased of oil recovery is observed. Foam may form when CO<sub>2</sub> is injected into the

surfactant inside the core which shown in Figure 16 after 2<sup>nd</sup> cycle of FAWAG-CO<sub>2</sub> is started and the surfactant injected produced foam which formed earlier. The foam may have redirected CO<sub>2</sub> into the unswept areas of the core. After 2<sup>nd</sup> cycle of FAWAG-CO<sub>2</sub> is completed, 86.54 % of the OOIP is produced as shown in Figure 15 and Table 4.



**Figure 15: Oil recovery factor (%) versus PV injected, at reservoir temperature 98 oC, constant injection rate of 1 cc/min, and injection pressure of 1700 psi (FAWAG-CO<sub>2</sub> + FW (2.5wt% SDS in 30000 ppm brine))**

**Table 4: Summary of the oil produced from each stages of coreflooding (FAWAG-CO<sub>2</sub> + FW (2.5wt% SDS in 30000 ppm brine))**

	Method of injection	Volume of oil produced (cc)	Oil Recovery Factor (% OOIP)
<b>Secondary Recovery</b>	Waterflooding	2	15.38
<b>Tertiary Recovery (1<sup>st</sup> cycle)</b>	1 <sup>st</sup> surfactant injection	5.2	40
<b>Tertiary Recovery (1<sup>st</sup> cycle)</b>	1 <sup>st</sup> gas injection	8.05	61.9
<b>Tertiary Recovery (2<sup>nd</sup> cycle)</b>	2 <sup>nd</sup> surfactant injection	10.05	77.30
<b>Tertiary Recovery (2<sup>nd</sup> cycle)</b>	2 <sup>nd</sup> gas injection	11.25	86.54



**Figure 16: Foam produced during surfactant injection of 2nd FAWAG-CO<sub>2</sub> cycle**

#### 4.4.2 FAWAG-CO<sub>2</sub> + LSW (2.5wt% SDS in 5000 ppm brine)

In this set of test, the core that being used is core B-1. Similar to the earlier coreflooding test, the core is injected first with FW and the absolute permeability for the core is 6.2 md. Then oil is injected at a similar injection rate and pressure. The volume of water produced is 13.5 cc which mean,  $S_{oi}$  is 0.79 and  $S_{wc}$  is 0.21. The saturation value obtained is almost similar to core B-2. After  $S_{oi}$  and  $S_{wc}$  establishment, waterflooding is directly started. The recovery from waterflooding is a shown in Figure 17 and Table 5. 2 cycle of FAWAG-CO<sub>2</sub> also being applied to this core. Similar to before, the oil recovery increasing significantly when FAWAG-CO<sub>2</sub> is started compared to waterflooding. After the last gas injection, the total oil production is 94.8 % of OOIP.

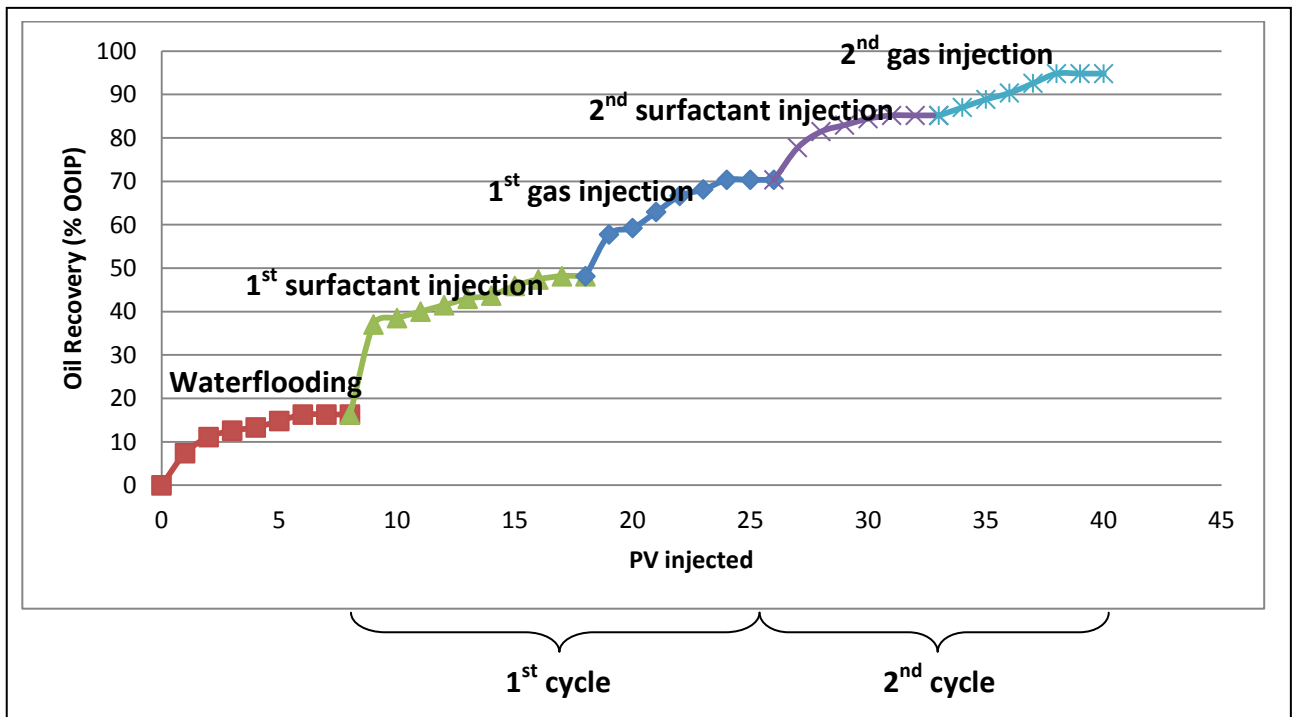
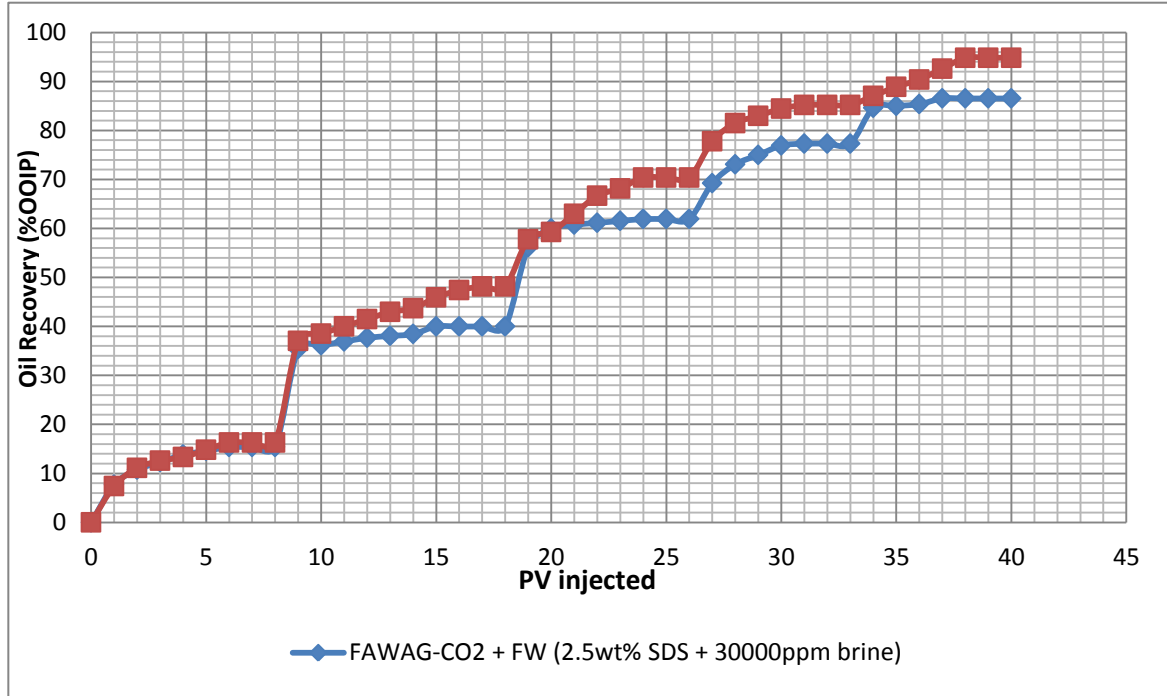


Figure 17: Oil recovery factor (%) versus PV injected, at reservoir temperature 98 °C, constant injection rate of 1 cc/min, and injection pressure of 1700 psi (FAWAG-CO<sub>2</sub> + LSW (2.5wt% SDS in 5000 ppm brine))

**Table 5: Summary of the oil produced from each stages of coreflooding (FAWAG-CO<sub>2</sub> + LSW (2.5wt% SDS in 5000 ppm brine))**

	<b>Method of injection</b>	<b>Volume of oil produced (cc)</b>	<b>Oil Recovery Factor (% OOIP)</b>
<b>Secondary Recovery</b>	Waterflooding	2.2	16.3
<b>Tertiary Recovery (1<sup>st</sup> cycle)</b>	1 <sup>st</sup> surfactant injection	6.5	48.1
<b>Tertiary Recovery (1<sup>st</sup> cycle)</b>	1 <sup>st</sup> gas injection	9.5	70.4
<b>Tertiary Recovery (2<sup>nd</sup> cycle)</b>	2 <sup>nd</sup> surfactant injection	11.5	85.2
<b>Tertiary Recovery (2<sup>nd</sup> cycle)</b>	2 <sup>nd</sup> gas injection	12.8	94.8

#### 4.4.3 Comparison between FAWAG-CO<sub>2</sub> + FW (2.5wt% SDS in 30000 ppm brine) and FAWAG-CO<sub>2</sub> + LSW (2.5wt% SDS in 5000 ppm brine)



**Figure 18: Comparison of oil recovery (% OOIP) vs PV injected between FAWAG-CO<sub>2</sub> + FW (2.5wt% SDS in 30000 ppm brine) and FAWAG-CO<sub>2</sub> + LSW (2.5wt% SDS in 5000 ppm brine)**

Figure 18 show the comparison of the oil recovery as a function of time for the two set of coreflooding test. The use of LSW during FAWAG-CO<sub>2</sub> improved the oil recovery at each stages of production compared to the use of FW. In total FAWAG-CO<sub>2</sub> + LSW (2.5wt% SDS in 5000 ppm brine) able to produced 94.8% of OOIP which is 8.26% higher compared to FAWAG-CO<sub>2</sub> + FW (2.5wt% SDS in 30000 ppm brine) which able to produce 86.54% of OOIP. The recovery may increase due to wettability alteration of the sandstone into more water wet. At low capillary pressure and slightly water-wet conditions, maximum oil recovery can be reached (Morrow *et al.*, 1998). When the high saline formation water is exchanged by the low saline water, active cations are desorbed from the clay surface due to desorption of organic material by an ordinary acid-base reaction (Austad *et al.*, 2010). However, since the formation brine that being used in the

first test is highly saline (30 000 ppm) the adsorption of organic material from the crude oil would most likely be small (Aksulu *et al.*, 2012). Adsorption of organic material onto the clay surface may create a less water-wet condition inside the core which might happen to core B-2. This condition can be clearly explained and observed if the pH changes during the coreflooding are noted. Similar observations of increase in the water-wetness of the core sample with decrease in brine salinity have been reported (Tang and Morrow 1999, 1996). Tang and Morrow (1999) reported similar increase in oil recovery from reduction in brine salinity which resulted in an increase in water-wetness of the cores. The reason for this wetting trend with respect to salinity variation is not clear. Tang and Morrow (1998) hypothesized that the increase in recovery they observed in their experiment may be related to the transfer of a fraction of the fine particles from the rock walls to the oil water interface during the course of displacement. If this hypothesis is correct, combining with the ability of foam to control mobility of CO<sub>2</sub> as foam tend to form in a high permeability pore throat, significant oil recovery increment will be observed.

## **CHAPTER 5: CONCLUSION AND RECOMMENDATION**

### **5.1 Conclusion**

Two set of experiment was done on Berea cores for low salinity effects during FAWAG-CO<sub>2</sub> by flooding the core with formation brine, two different formulations of surfactant solution and carbon dioxide. The core was flooded with a constant rate of 1 cc/min at reservoir temperature, 98°C. The main conclusions from the work are:

1. FAWAG-CO<sub>2</sub> is performed on two different core samples and Dulang crude oil showed improvement in the reduction of residual oil saturation by 8.26% and improvement in the oil recovery efficiency. Incremental oil recovery was observed when the salinity of the brine was reduced from 30000 ppm to 5000 ppm.

2. The application of LSW in FAWAG-CO<sub>2</sub> has the potential for improved oil recovery for tertiary recovery process. When LSW is used in FAWAG-CO<sub>2</sub> for the tertiary oil recovery, simultaneous effect of wettability alteration, fines migration and gas mobility control can be expected.
3. Results from this study indicate that there is a potential for increasing oil production by improving oil recovery in matured oil reservoirs through the application of low salinity brine during FAWAG-CO<sub>2</sub>. One cost-effective means of achieving low salinity brine injection is by diluting the formation water by mixing with seawater. Two other possible low salinity options for field application will be the use of low salinity water reservoir, where available, or the setting up of a brine desalination plant.

## **5.2 Recommendation**

For future reference, a proper chemical screening procedure should be done. It is recommended that a much better surfactant with industry standards is use for testing. For the foaming test, a much proper experiment setup such as the Ross Miles test is highly recommended so that the test can be done at reservoir temperature and its interaction with crude oil can be observed. The phase behavior testing also should be done with the presence of crude oil to observe the emulsion form when different concentration of surfactant is used. IFT test by using Pendant drop method also should be included in the chemical screening process. The test can help determine which surfactant is better and the optimum concentration to be used.

For the coreflooding test, the formation brine used should have the similar composition as the formation brine obtained from the same field as the crude that being used. All the test should be done at reservoir temperature and pressure. To observe the low salinity effect, much more factor have to be considered and observed such as presence of clay in the core, the effluent composition, pH changes and formation brine composition. Salinity of brine that is being tested should be more than two to determine the optimum salinity and much more reliable result.



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